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March 25, 2011

British Columbia Public Interest Advocacy Centre
Suite 209 – 1090 West Pender Street
Vancouver, BC
V6E 2N7

Attention: Mr. James L. Quail, Executive Director

Dear Mr. Quail:

Re: FortisBC Energy Inc. ("FEI") and FortisBC Energy (Vancouver Island) Inc. ("FEVI")[1] (collectively the "Companies")
Price Risk Management Review of Objectives and Hedging Strategy and FEI 2011-2014 Price Risk Management Plan ("PRMP")

Response to the British Columbia Public Interest Advocacy Centre on behalf of the British Columbia Old Age Pensioners Organization et al ("BCOAPO") Information Request ("IR") No. 1

On January 27, 2011, the Companies filed the Application as referenced above. In accordance with Commission Order No. G-23-11 setting out the Regulatory Timetable for the review of the Application, the Companies respectfully submit the attached response to response to BCOAPO IR No. 1.

If there are any questions regarding the attached, please contact Mike Hopkins at (604) 592-7842.

Yours very truly,

FORTISBC ENERGY INC.

Original signed by: Brian Noel

For: Diane Roy

Attachment

cc (e-mail only): Erica Hamilton, Commission Secretary
Registered Parties

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[1] Formerly Terasen Gas Inc. and Terasen Gas (Vancouver Island) Inc. respectively.

1.0 Reference: Exhibit B-1, page 2

1.1 Does FortisBC agree that minimizing exposure to counterparty risk would be or has been a useful objective of any price risk management plan?

Response:

Yes, FEI does agree that minimizing exposure to counterparty risk has been and is a useful and prudent price risk management plan objective.

Prudent management of counterparty credit risk is an important underlying objective that will be managed FEI to help it achieve the primary objectives of the PRMP as well as maintaining cost effectiveness of the portfolio.

1.2 Please explain how FortisBC mitigated counterparty risk in the past.

Response:

FortisBC manages financial counterparty exposure by entering into financial contracts with a number of solid and highly-rated financial counterparties. If market prices decline such that the amount FEI owes a particular counterparty on a forward looking basis exceeds that counterparty's credit limit threshold, the counterparty may halt trading with FEI until market prices change or monthly invoice settlements reduce the amount owing. If market prices increase such that the amount a particular counterparty owes FEI exceeds the set credit limit threshold, FEI will halt trading with that counterparty until market prices change or monthly invoice settlements reduce the receivable amount. While this has happened on occasion in the past, by having a number of financial counterparties FEI has avoided any adverse effects of market price movements on its hedging implementation.

1.3 Does FortisBC believe that its hedging program has lowered the market price of gas or that because of hedging gains, its system gas customers have paid less than they would have without a hedging program?

Response:

Not necessarily. As seen in the response to BCUC IR 1.1.1.1, hedging gains or losses as measured against market prices have varied from year to year. As discussed in Section 2.3 of the Review Report, it must be understood that in general utilities use price risk management strategies in order to reduce the uncertainty of future market prices which impact gas costs that are passed onto customers through rates and without mark up. It is important to distinguish this from attempting to "beat the market" or achieving the lowest pricing available. In other words, hedging is about providing insurance to protect gas customers from exposure to extreme price volatility and economic hardship, and it is NOT about market speculation or trading in and out to generate gains. Various customer surveys and focus groups conducted by the Companies have indicated that customers value some sort of rate stability and also realize that some degree of certainty in rates may involve costs (i.e. hedging costs) in order to achieve such stability in rates, as presented in Appendix B of the Review Report.

1.4 The evidence states that *"An underlying objective has been to meet these primary objectives at a reasonable cost."* Please define what "reasonable cost" means quantitatively and please specify what costs are included, e.g., are all costs of undertaking risk management, internal, including full cost allocations (legal, administrative, financial, overhead, etc.,) plus hedging costs and external costs included?

Response:

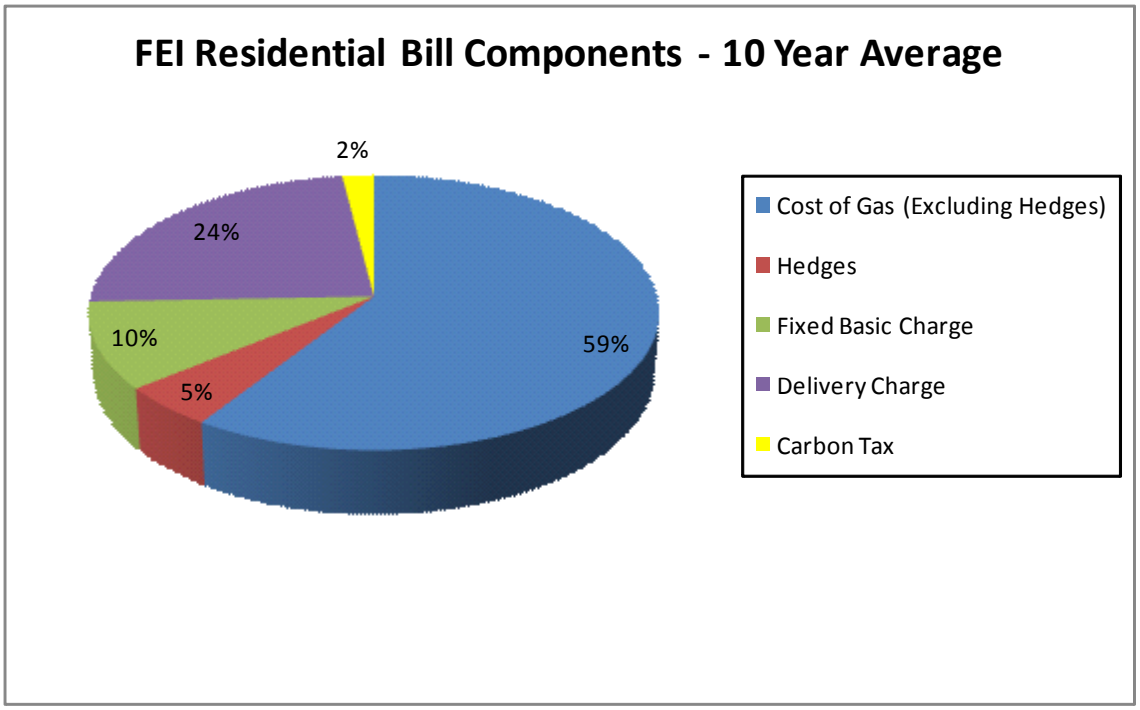
An underlying objective has been to meet these primary objectives at a reasonable cost. Reasonable cost means providing price risk management to reduce rate volatility and improve competitiveness on behalf of customers at a cost that is not significant to customers in terms of their annual bill. The costs relating to price risk management refers to both indirect costs for the management and administration related to the hedging program, including external costs such as consulting, as well as direct costs related to any potential hedging costs (or gains) resulting from effective hedging prices relative to actual market index prices.

The indirect costs include those related to price risk management and oversight, credit and compliance, legal and regulatory work and any external consultant reviews. These costs were discussed in the response to BCUC IR 1.4.3.1. On an annual basis, even including consultant costs which are typically not required each year, these indirect costs represent approximately $0.25 per customer on an annual basis and so are not considered to be material. These costs

are included in Core Market Administration Expense as part of the cost of gas that is flowed through to customers and reviewed by the Commission. The Utilities prudently and appropriately manage these costs for customers.

The direct costs include any hedging gains or costs resulting from the effective hedge prices relative to market prices. In recent years, with the decline in market prices, hedging costs have outweighed hedging gains, as discussed in the response to BCUC IR 1.1.1.1. The average of these hedging gains and costs over the past ten years has been a cost of about $65.3 million compared to about $848.4 million of total gas costs. On an annual bill basis, this equates to an approximate annual cost per customer of $56. Graphically, the cost of hedges over the past years compared to the other components of the residential customer bill, including carbon tax, is as follows.

Figure 1: FEI Residential Bill Components – 10 Year Average



This net cost related to hedging has not been significant over the past ten years. However, the Utilities believe the proposed enhanced hedging program can improve on these results by providing greater response to market conditions and through a greater use of options to capture downside market price movements and reduce the potential for out-of-market outcomes. The analysis performed by the consultant RiskCentrix, provided in Section 7.1 and Appendix A of the

Review Report, illustrates that, based on 95% probability, expected hedging costs in an extremely low priced scenario, such as $1/GJ, would not be as significant as annual hedging costs of the last few years.

Based on the discussion of these direct and indirect costs, the Utilities believe that the hedging program has met the objectives at a reasonable cost. However, the proposed hedging program will significantly reduce the potential for significant direct hedging costs, thereby improving the ability to provide rate volatility reduction and competitive rates at a reasonable cost for customers in the future.

1.5 Please provide a full breakdown of all costs historically incurred for risk management by TGI (now FortisBC Energy) on an annual basis, including fully allocated internal costs.

Response:

Please refer to the responses to BCUC IRs 1.1.1.1 and 1.4.3 for an explanation of all direct and indirect costs associated with its risk management program.

2.0 Reference: Exhibit B-1, page 10, Figure 1

2.1 Please provide full details as to how the reduction in volatility solely attributed to hedging is quantified and separated from the reduction in volatility due to quarterly rate adjustments and the reduction in volatility due to the Equal Payment Plan.

Response:

The reduction in volatility in natural gas rates is achieved by a combination of hedging, deferral accounts and the quarterly rate setting mechanism and the impacts are difficult to separately quantify in a hindsight review. Nevertheless, please refer to the responses to BCOAPO IRs 1.2.2 and 1.2.4 for an assessment of the reduction in volatility due to hedging over the past several years based on a stated set of assumptions.

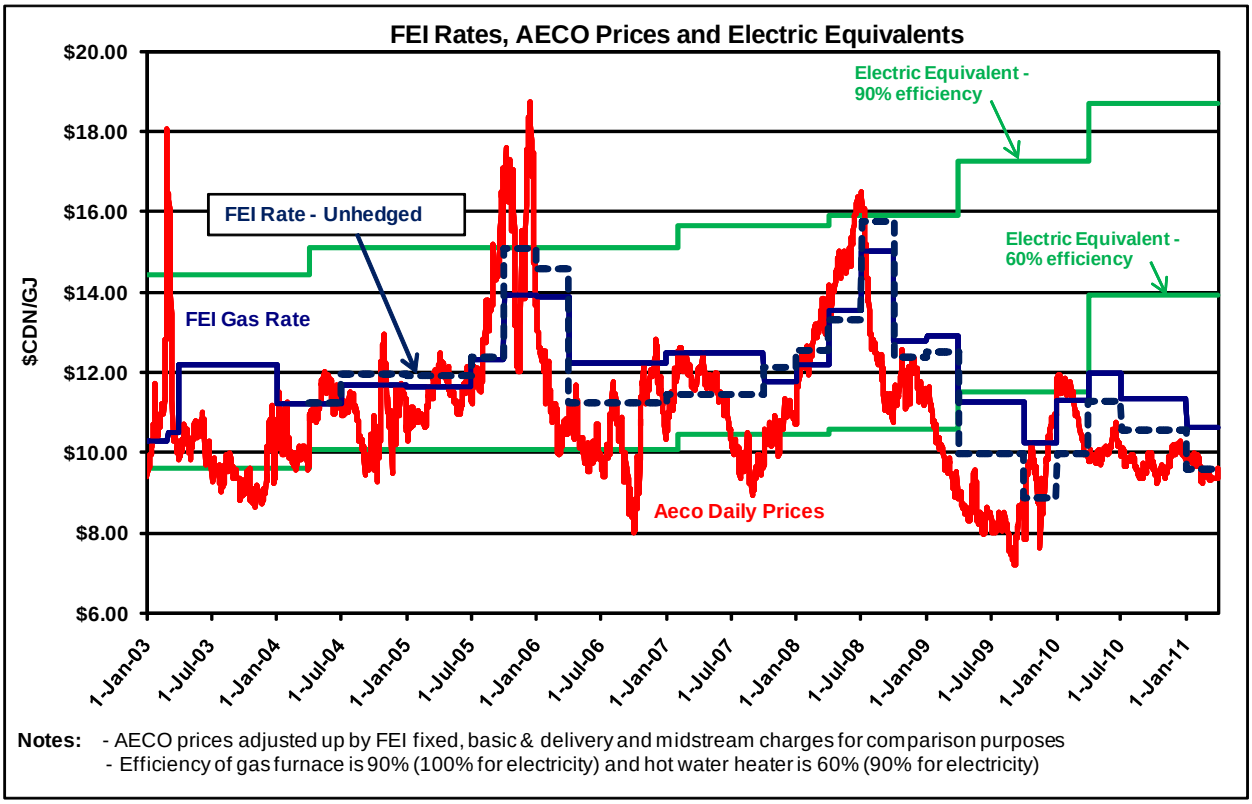
The quarterly rate setting mechanism and the use of deferral account balances provide some form of rate volatility reduction to customer bills but have no effect on the underlying price of the commodity and should not be considered a replacement for natural gas hedging in effectively managing market price risk. As discussed in Section 3.5.1.5 of the Review Report, the Equal Payment Plan ("EPP") is not reflected in approved published rates but rather a mechanism available to individual customers to smooth the impact of volume consumption on their bills over a 12 month period and therefore making it easier to budget for their household energy expenses. The EPP does not have any effect on the underlying price of the commodity.

2.2 Please add a line to this figure showing what the TGI rates would have been in the absence of hedging, assuming that all other elements of the gas supply portfolio including the ACP, monetizing underutilized resources, etc., and the regulatory framework (e.g., quarterly adjustments, CCRA, Equal Payment Plan) remained as they were. Please provide a full explanation as to the details, calculations, and assumptions underlying the line added.

Response:

The graph shown in Figure 1 in Section 2.4.1 of the Review Report has been revised, and attached below, to include a line to provide a proxy of what the FEI rate would have been in the absence of hedging. FEI notes that while it is not possible to precisely restate the historical results to incorporate all the changes that may have occurred in the absence of any commodity hedging, FEI has undertaken to adjust the historical and recorded gas cost data to remove the

commodity hedging from the historical commodity recovery rates to develop a proxy of the "unhedged" rate. Based on the historical data reasonably available, FEI has utilized the commencement of the Essential Services Model and the establishment of the CCRA and MCRA gas cost deferral accounts as the starting point for the unhedged rate analysis.



In determining the unhedged FEI rate proxy, the fixed basic charges, and variable delivery and midstream charges were left unchanged. Although the historical midstream costs include a small amount of hedging related to basis swaps, the impact to the historical annual midstream rates for the period being shown has been excluded as it amounts to less than ± $0.01/GJ in the annual rate. The commodity recovery rate, or CCRA rate, has been recalculated to approximate an unhedged rate by leaving the effective dates of the original rate changes unchanged and by adjusting the commodity cost forecasts to remove the hedging and also adjusting the CCRA deferral balances to remove the hedging impacts.

2.3 Does FortisBC believe that it can either "time the gas commodity market" or otherwise beat the market price for gas in the long run and on average? Please explain fully indicating what exactly the utility means when it speaks of maintaining "competitiveness" of gas commodity prices.

Response:

The Utilities do not believe that they can "time the commodity gas market" or otherwise beat the market price for gas in the long run and on average. As discussed in Section 2.3 of the Review Report, the objective of the hedging program is not to "beat the market" as this is a difficult endeavour and can lead to speculation which may ultimately result in higher rate volatility or direct hedging costs for customers.

When the Utilities speak of maintaining competitiveness of gas commodity prices they are referring to maintaining the competitiveness of natural gas in comparison with other sources of energy available to energy consumers in B.C. At this time, the Utilities believe that competitiveness with electricity is a key objective of managing gas costs and the hedging program. Maintaining competitiveness potentially helps maintain natural gas system throughput which, in turn, has a positive impact to delivery rates. If natural gas competitiveness declines, then customer migration away from natural gas could occur which would reduce system throughput and ultimately lead to higher delivery rates for remaining customers, all else equal. This is discussed fully in Section 4.4.1 of the Review Report.

2.4 Please provide the reduction in volatility of the total bill in Standard Deviations which FortisBC attributes to its hedging activities for each of the years represented on the horizontal axis of this graph. Please provide full support for this response.

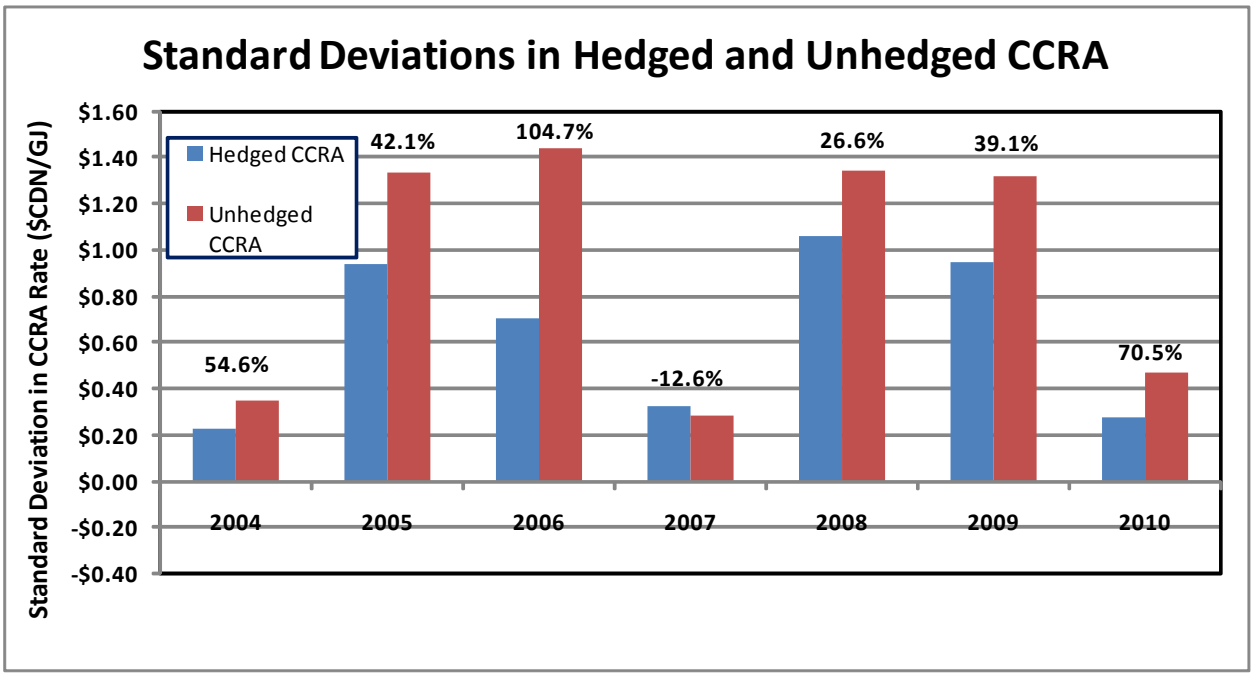
Response:

Please refer to the response to BCOAPO IR 1.2.2.

See figure 1 below which illustrates the standard deviations of the actual hedged CCRA rate and the illustrative CCRA rate if no hedges were in place from April 2004 to December 2010. The percentages displayed above each set of columns represent the magnitude of difference between the hedged and unhedged CCRA rate.

Note that unhedged CCRA rate is more volatile than the hedged CCRA for all but one year from 2004 to 2010. In 2006, the unhedged CCRA rate was about 105% more volatile than the hedged CCRA rate.

Figure 1: Standard Deviations by Year for Hedged and Unhedged CCRA Rate



2.5 For each year shown on this graph and for each year that TGI undertook hedging, please provide a list that states full details of all hedging instruments used by year and include the identification of the counterparty if applicable. Please include the type of instrument, the associated volumes hedged, direct costs, allocated costs, net results of the hedge, and the expiry or strike date.

Response:

The table below summarizes hedging instruments, hedging costs/gains and volume hedged on an annual basis. The name of the counterparty and details of each transaction is not provided due to market sensitivity of disclosing operations of other companies and by doing so does not add to the discussion of hedging gains and costs of hedging instruments.

For costs related to management and administration of the overall hedging strategy pursuant to the Price Risk Management Plan, please refer to the responses to BCUC IRs 1.4.3.1, 1.4.3.2, 1.4.3.3, and 1.4.3.4.

	2003		2004	
	Gains / (Costs)	Hedged Volume (GJ)	Gains / (Costs)	Hedged Volume (GJ)
Financial Fixed	$13,308,613	27,938,250	$16,180,187	36,034,699
Costless Collars	($3,501,605)	18,135,000	($1,353,180)	13,039,500
Basis Swaps	($1,121,013)	1,445,427	($2,727,218)	949,550
Calls	$0		$0	
Industrial	$1,609,590	231,554	$1,492,398	925,999
Total	$10,295,585	47,750,232	$13,592,188	50,949,748

	2005		2006	
	Gains / (Costs)	Hedged Volume (GJ)	Gains / (Costs)	Hedged Volume (GJ)
Financial Fixed	$63,443,233	56,161,887	($75,059,847)	47,721,411
Costless Collars	$7,318,412	12,715,600	($24,952)	5,194,800
Basis Swaps	($2,481,786)	2,144,551	$651,378	5,997,119
Calls	($1,590,270)	1,342,000	($13,043,081)	11,104,300
Industrial				
Total	$66,689,589	72,364,038	($87,476,501)	70,017,630

	2007		2008	
	Gains / (Costs)	Hedged Volume (GJ)	Gains / (Costs)	Hedged Volume (GJ)
Financial Fixed	($117,924,893)	49,813,300	($22,607,026)	36,188,974
Costless Collars	($1,670,273)	2,310,750	($955,268)	2,926,850
Basis Swaps	$1,608,145	8,032,774	($1,447,226)	7,780,700
Calls	($20,023,329)	13,746,700	($16,838,363)	13,165,500
Industrial				
Total	($138,010,351)	73,903,525	($41,847,882)	60,062,024

	2009		2010	
	Gains / (Costs)	Hedged Volume (GJ)	Gains / (Costs)	Hedged Volume (GJ)
Financial Fixed	($134,061,221)	38,326,914	($124,842,095)	39,722,870
Costless Collars	($20,417,898)	7,936,637	($10,524,415)	5,938,974
Basis Swaps	($2,664,092)	4,751,033	($367,972)	13,412,949
Calls	($7,710,476)	5,033,699	($541,549)	388,514
Industrial				
Total	($164,853,687)	56,048,283	($136,276,030)	59,463,307

2.6 Please confirm that all counterparties to TGI in its hedging activities have been unaffiliated third parties. If unable to so confirm, please explain fully.

Response:

Confirmed.

2.7 Please indicate whether unregulated affiliates of the regulated utility are privy to any details with respect to the utility's hedging activities when the utility undertakes these activities or when the associated financial instruments have yet to expire.

Response:

Affiliated companies, both regulated and non-regulated, share common leadership and certain corporate functions, therefore there is knowledge of financial transactions within the affiliated group of companies. The Company does not see what concern is being raised by the question.

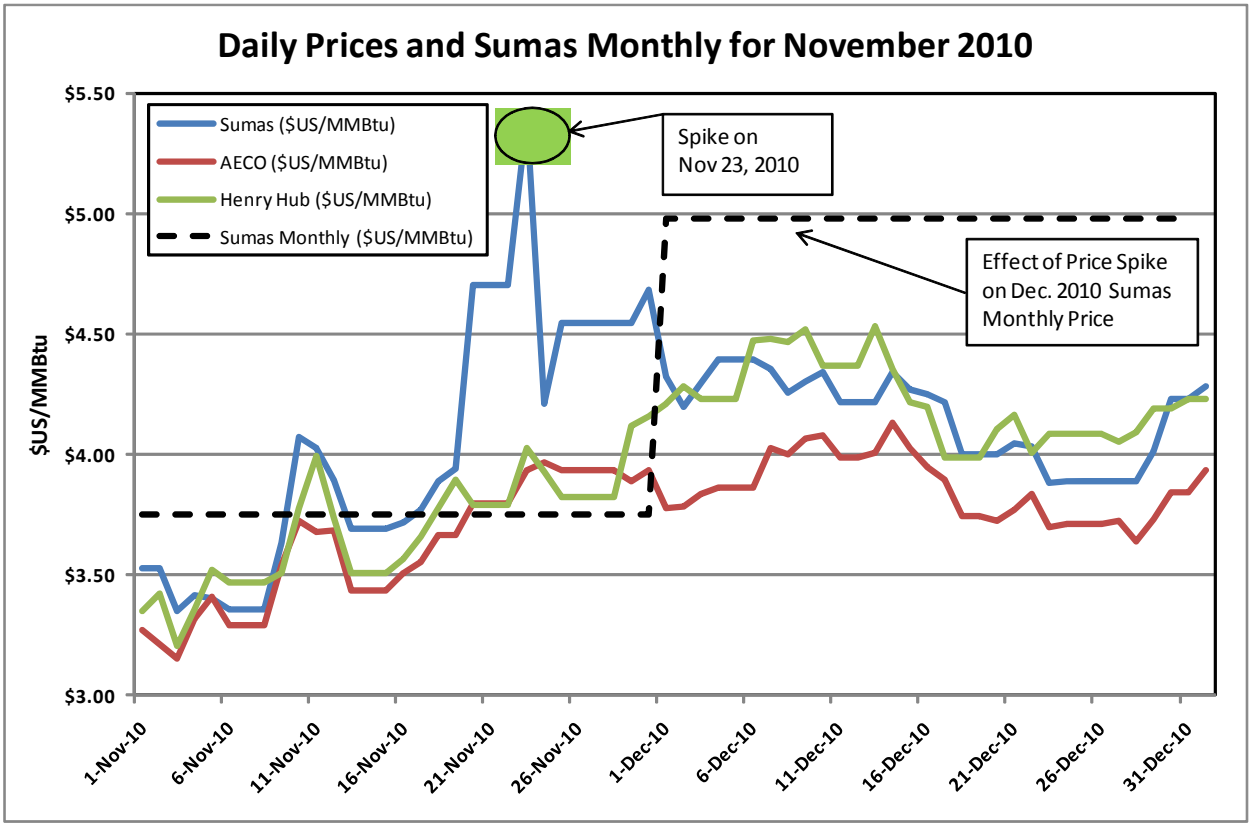
2.8 Please confirm that temporary commodity price spikes only impact customers' bills to the extent that the utility makes spot purchases during the duration of the spike.

Response:

Since the Companies do not hedge 100% of their portfolios any spike or dip in commodity prices will have an impact on customer rates. Additionally, there is no way of accurately knowing if the current environment that one is in, is a high price or a low price environment and this can only be deduced after the fact.

Customer bills are not only impacted by purchases made during the duration of a price spike or dip, they can also be impacted by the influence price excursions may have on monthly index for the following month. For instance, the Sumas price spike that occurred during the end of November 2010 caused the monthly Sumas price for December 2010 to be higher than it otherwise would have been expected since Sumas monthly prices are set during the last week of the preceding month. Figure 1 below illustrates the Sumas price spike during November 2010 was a contributing factor to increasing the December 2010 Sumas monthly index. Thus, it is important to have hedging strategies to deal with these market realities, which are influenced by the regional infrastructure constraints during cold periods.

Figure 1: Sumas Price Spike and December 2010 Monthly Price



FEI incorporates a number of factors with respect to the CCRA rate setting mechanism such as existing deferral account balances (which are a result of variances between the actual incurred gas costs and the forecast gas costs upon which the existing recovery rate was established), and the forecast gas costs for the prospective 12-month period based on the forward prices and any forecast hedging costs or gains. Commodity price spikes can affect both the actual incurred gas costs as well as the forward prices, both of which can have an effect on setting the CCRA rate.

2.9 Please confirm that a winter peaking service would also mitigate the impact of price spikes.

Response:

No, a winter peaking supply service will not mitigate price spikes as it is subject to the day price that is in effect. The purpose of a winter peaking supply service is to ensure security of supply to meet peaking loads during extreme weather conditions.

Additionally, a large majority of the hedging undertaken by FEI is incorporating volumes in the Commodity Cost Reconciliation Account ("CCRA"), which is composed of 100% load factor baseload gas supply under the Essential Services Model and supports the Commodity Unbundling Program. Peaking gas supply, which is part of the midstream portfolio to serve winter demand, would only be utilized for a few days during each winter in extreme weather conditions. As a result, this supply provides a more cost effective option than term supply or storage services. However, winter peaking supply is subject to the same daily prices which will be in effect during a cold snap.

2.10 To FortisBC's knowledge, did any of the utility's counterparties engage contemporaneously in hedging or other financial activities with affiliated unregulated entities?

Response:

None of the utility's counterparties are engaged in commodity hedging with FortisBC unregulated affiliates that are subsidiaries of FortisBC Holdings Inc. or with FortisBC Inc. In addition, FEI is not aware of any commodity hedging activities with other non-regulated Fortis Inc. affiliates. To the extent there are such hedging activities, FEI does not have any knowledge of the details of those transactions. FEI does undertake hedging with major financial institutions; therefore, its affiliated entities have entered into other financial activities, such as credit agreements and commercial paper or debenture issuance activities and foreign exchange transactions.

3.0 Reference: Exhibit B-1, page 14

Preamble: The evidence states*, "…a significant portion of the physical portfolio is comprised of index priced gas subject to market price movements."*

3.1 Does the physical portfolio include any quantities of gas at fixed prices or prices escalated only at the rate of inflation? If so, please provide details. If not, please explain why not.

Response:

No, currently, FortisBC does not have any physical deals in place at fixed prices or deals escalating only at the rate of inflation. Typically the supply portfolio is comprised of index priced gas that is subject to market price movements. Generally, producers are unwilling to provide physical supply at a fixed price because producers do not want to hedge during the same terms as FortisBC. Most producers and utilities prefer to transact for financial transactions with strong, creditworthy counterparties such as chartered banks and financial institutions with a credit rating of single A or higher. Additionally, substituting a financial hedge with physical supply at a fixed price can have negative consequences in terms of counterparty performance and credit risk. In the event of a default by a producer that is supplying FortisBC with physical supply at a fixed price, this may potentially expose FortisBC's portfolio to not only physical supply risk but price risk as well due to the loss of both the benefits of physical supply and price risk mitigation of that one fixed price deal. FortisBC prefers to rely on producers to provide physical supply and financial institutions to provide price risk mitigation as it allows for greater diversity and security of both the physical and financial portions of the portfolio.

4.0 Reference: Exhibit B-1, page 22, Figure 7

4.1 Is it fair to conclude from this figure that a large upward price spike has occurred about once every two or two and a half years?

Response:

Large price spikes is an ambiguous term since the magnitude of the spike must be viewed in context of the prices immediately prior to and after the spike in price. Additionally, there is absolutely no way of knowing or predicting that a price spike is about to happen in the near future with any degree of accuracy. One thing to note is that price spikes are equally as likely to occur in the summer months as the winter months. Price spikes in the summer months are usually attributed to production being shut in due to hurricane damage and prices in the winter months usually spike if storage levels dip below historical averages or if demand is high in response to colder than normal weather.

FortisBC is assuming this question is referring to the 4 or 5 very large price spikes experienced in December 2000, February 2003, September 2005, December 2005, and June 2008. The purpose of this figure is to highlight the fact that although catastrophic events do cause prices to spike abnormally, there does still exist price volatility in the marketplace exclusive of these catastrophic occurrences. Although these extremely large price increases occur infrequently, market price volatility is still prevalent even in 'normal' price environments. Customer surveys and customer focus groups conducted by the Companies have indicated that its customers prefer a level of volatility reduction in their rates and one of the objectives of the PRMP is to manage and reduce market price volatility in customer rates.

5.0 Reference: Exhibit B-1, page 24, Figure 8

5.1 Please indicate the data source for this figure.

Response:

The data contained in Figure 8 is collected and updated weekly by the Companies. The data itself is from actual price settles from the New York Mercantile Exchange ("NYMEX") for natural gas, light sweet crude oil, heating oil, fuel oil, and Central Appalachian coal. The respective price for each commodity is then standardized to $US/MMBtu by using industry standard conversion factors.

5.2 Do the forward prices indicate futures prices traded on the NYMEX?

Response:

Yes, the forward prices for each commodity are futures prices traded on the NYMEX. The prices in Figure 8 are as of price settles on January 13, 2011.

6.0 Reference: Exhibit B-1, page 52

Preamble: The evidence states: *"Therefore, in order to attract new customers or those planning to retrofit with new equipment, TGI must maintain a commodity rate below $8.21/GJ for 2011 and below $13.73/GJ by 2014."*

6.1 Does TGI/FortisBC believe that it can maintain commodity rates at or below these levels at a reasonable cost and regardless of future market prices for gas? Please explain fully.

Response:

The Utility believes that it can improve the probability of maintaining commodity rates below these levels at a reasonable cost if the proposed hedging program is approved. This probability of maintaining competitiveness for this space heating application will depend on a number of factors, including future electricity rates, future carbon tax rates and the movement of market natural gas prices. Further, price is only one factor that determines the competitiveness of natural gas against other energy forms. Government policy and a customer's perception towards the product are also contributing factors that can impact a product's competitiveness.

The proposed hedging program helps with this competitiveness by implementing hedges according to the programmatic, value, defensive and basis strategies outlined in Section 8 the Review Report. For example, the defensive hedging strategy includes the execution of hedges if commodity portfolio costs are expected to breach predefined prices that are based on competitive benchmarks. So an increase in market prices can trigger the implementation of defensive hedging which helps to preserve competitiveness should market prices continue to move higher. The enhanced hedging strategy, including a greater use of options, will also ensure that this price protection and competitiveness is achieved at a reasonable cost to customers.

These space heating competitive benchmarks are one component of maintaining competitiveness. As discussed in Section 4.4.5.4 of the Review Report, the hot water heating competitive benchmarks are significantly lower and therefore present a greater challenge to the Utilities. As Figure 23 illustrates, the competitive benchmarks for hot water heating for new or retro-fit customers (under the 50% British Columbia Hydro and Power Authority rate increases scenario) are near current market gas prices. The proposed enhanced hedging program, if approved, will help in this regard.

7.0 Reference: Exhibit B-1, page 73

Preamble: The evidence states: *"Hedging is frequently compared to the use of insurance to protect against uncertain events. For example, homeowners typically purchase home insurance to protect their home and belongings against unforeseen or uncertain events such as fires or earthquake. The insurance analogy is appropriate because it reflects the desire to protect against catastrophic events (or market price spikes) for a modest cost. Homeowners are willing to pay premiums each year for this protection and typically do not speculate regarding the timing of the adverse events and defer insurance protection to another year. Furthermore, homeowners are not likely to cancel insurance coverage if a catastrophic event has not occurred in the recent past - their concern is solely with the risk of exposure to future events. This insurance protection provides value to customers, giving them security and peace of mind. Ultimately, the hedging program should provide value for customers over the long run, yielding an appropriate balance of the benefit of risk mitigation with reasonable, acceptable cost for this protection"*

7.1 This statement appears to indicate that customers should expect to pay a premium above market price on average in the long run for "hedging insurance." Please confirm that it is not the utility's position that on average and over time hedging gains should not be expected. If unable to so confirm, please explain fully.

Response:

It is the Utilities' position that on average and over time hedging gains should not be expected. Given the volatility and uncertainty in future market gas prices, the Utilities are not able to predict if hedging gains or costs will occur over the long run or in the future. As discussed in the response to BCOAPO IR 1.2.3, the Utilities do not expect to "beat the market" or incur gas costs that are lower than those based on market prices. However, it is also expected that, over the long run, hedging costs, if they occur, should be minimal and not a significant portion of the customers' annual bills. As discussed in the response to BCUC IR 1.1.1.1, over the past ten years or so, the Utilities have incurred net hedging costs. This is largely due to the significant decline in market gas prices during the past few years and is also not indicative of future market price movements or hedging costs. However, the proposed hedging program will help ensure that the objectives are met while also reducing the potential for significant hedging costs going forward.

8.0 Reference: Exhibit B-1, page 62

Preamble: The evidence states: *"An effective hedging strategy can reduce the frequency as well as the magnitude of commodity rate changes and help ensure cost effective and competitive rates for natural gas customers."*

8.1 Please indicate how any hedging strategy can reduce the frequency of commodity rate changes for bundled system gas customers whose commodity rates are adjusted quarterly.

Response:

For the purposes of answering this question, the Utilities have assumed that bundled gas customers are defined as those customers who have chosen to remain with the FEI standard commodity offering instead of a marketer fixed price offering. As such, they would have their commodity rate reviewed, and potentially adjusted, on a quarterly basis. The FEI current rate setting mechanism includes a deadband threshold criteria to determine if commodity rate changes are required.

A hedging strategy can reduce the frequency of commodity rate changes for gas customers whose commodity rates are adjusted quarterly. Because the quarterly rate adjustment mechanism includes a commodity deadband threshold of 95% to 105% to trigger a commodity rate change, a hedging program can improve the probability of maintaining commodity rates within this threshold. In other words, a hedging program provides greater commodity cost stability than an unhedged program, reducing the likelihood of quarterly rate changes. As such, the quarterly rate adjustment mechanism and hedging compliment each other in meeting the objectives.

9.0 Reference: Exhibit B-1, page 66

Preamble: The evidence states: *"In other words, under the EPP alone, consumers are artificially protected from market price volatility as they will ultimately have to pay the rate impacts of any market price fluctuations."*

9.1 Please confirm that the EPP, along with a spot-purchase-only gas supply portfolio, would be expected to protect customers from market price volatility in the event of high intra-month market volatility that was symmetrical about the mean monthly commodity price embedded in commodity rates.

Response:

The EPP along with a spot purchase only gas supply portfolio would protect customers from market price volatility depending upon customer load requirements. As long as spot market prices were symmetrical about the mean (i.e. upside and downside spot price movements from the mean within the month average to zero), and customers daily load requirements were also symmetrical in the same manner, then customers would not experience any volatility. However, if customer load requirements, for example, were higher during the beginning of the month when spot prices were also higher than the monthly mean, then customers would incur higher costs.

It should be noted that a spot-purchase-only gas supply portfolio is not something that the Utilities believe to be in the best interests of customers. This would not meet the Annual Contracting Plan's ("ACP") objectives of security and reliability of supply as spot gas in the B.C. marketplace can be difficult to purchase in periods of high demand. As such, the ACP provides a more optimal cost effective balance of diversified resources including seasonal supply, storage capacity, on-system liquefied natural gas, spot and peaking supply. While the size and liquidity of the Alberta market permits more availability of spot gas purchases on a day forward and even intra-day basis, the reduced liquidity at the Station 2 and Sumas market hubs in B.C. limits this availability.

9.2 Please indicate the sense in which the EPP provides protection that is any more artificial than (i) a marketer's fixed price offering, or (ii) utility commodity rates underpinned by a fixed price portfolio, or (iii) protection afforded by hedging activities.

Response:

The EPP provides rate volatility protection in a different manner than marketers' fixed price offerings, utility commodity rates underpinned by a fixed price portfolio or protection afforded by hedging activity. As discussed in Section 4.5.1.5 of the Review Report, the EPP provides customers with bill smoothing rather than rate smoothing. This is an important distinction. Bill smoothing means that customers receive the same monthly bill cost regardless of their consumption or natural gas commodity rates. Typically, EPP amounts are reviewed each quarter and if market prices and rates are more volatile, the customers' monthly bills are adjusted up or down to account for their actual usage and actual rates over the past number of months. In other words, these customers have been artificially protected from consumption and rates changes in order to have equal monthly bills. While many customers find value in this service, it is ultimately different than the protection provided by fixed rate offerings or a hedging program.

A fixed rate offering program, either provided by marketers or utilities, or a hedging program actually impact the market prices customers pay through rates by converting market prices to a more stable price through the use of financial derivatives or physical fixed price purchases. In these cases, the customers are paying what the marketer or utility has incurred and the prices incurred are reflected in rates. In the case of marketers, a margin for profit would also be included in their fixed rate offerings, while the utilities would not add any profit mark-up to their costs. Furthermore, customers monthly natural gas bills reflect their monthly consumption, unlike under the EPP.

9.3 Does FortisBC agree that in the case of a utility using a hedging program, in the long run and on average, customers should expect to pay the full cost of the commodity plus a hedging insurance premium to reflect the costs of hedging plus a premium for the shedding of some volatility risk?

Response:

Yes, based on past experience, the Utilities would agree that, on average, customers should expect to pay the full cost of the commodity program plus a hedging insurance premium to reflect the costs of hedging as a premium for the shedding of some volatility risk.

10.0 Reference: Exhibit B-1, page 67

Preamble: The evidence states: *"Some customers have returned to the TGI standard rate offering, which is subject to quarterly review and, at least historically, has been favourable relative to the average marketers' fixed rate products."*

10.1 Please provide a summary of the historical evidence that is favourable to the TGI/FortisBC standard offering compared to the average marketers' fixed rate products.

Response:

Please refer to the responses to BCUC IRs 1.7.1.1, 1.7.1.3, 1.7.1.4, 1.7.1.5, 1.13.1.1, 1.13.1.2, 1.13.1.3, and 1.13.1.4.

10.2 Regarding the perception that customers might save money by taking a marketer's fixed price offering, to what does FortisBC attribute customers' misperceptions of reality vis a vis marketers' offerings?

Response:

FEI believes that misconceptions regarding the likelihood of saving money have arisen for three primary reasons. These reasons are described below.

The first reason is described in the response to BCUC IR 1.7.1.4. Many customers that signed contracts understood that they were "guaranteed" savings. This issue was explored through a focus group[1] conducted in November 2010. The research moderator concluded that, "Customers of Gas Marketers were originally attracted by the promise of long-term savings and rate stability…All felt pressured into signing contracts by marketers, who used the fear of future price increases and aggressive sales pitches to get them to sign multi-year contracts."[2] While this research was qualitative in nature, FEI believes it is consistent with anecdotal and dispute information presented by consumers.

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[1] Customer Choice Program 2010 Program Summary and Recommendations, Appendix J, "Customer Choice and Commodity Pricing, Qualitative Research Findings," November 2010, submitted to the BCUC on November 23, 2010. This report is available at http://www.fortisbc.com/About/RegulatoryAffairs/GasUtility/NatGasBCUCSubmissions/Documents/101123_TGI_Customer_Choice_2010_Program_Summary_Recommendations.pdf

[2] Customer Choice and Commodity Pricing, Qualitative Research Findings, November 2010.

The second reason relates to the nature of the offer. Natural gas is typically considered a low involvement purchase. For example, consumers put much more thought into which TV they purchase. Consumers do not have a strong attitude about natural gas or energy products and may devote little effort to understanding the different sales offers. As such, misconceptions can easily arise.

The third reason misconceptions persist relates to the generally decreasing market price for natural gas and buyer's remorse, or more specifically, cognitive dissonance. Cognitive dissonance is defined as, "a state of psychological discomfort arising when a consumer tries to reconcile two conflicting states of mind, for example, the positive feeling of having chosen to buy a product and the negative feeling of being disappointed with it afterwards." [3] FEI is of the opinion that even in circumstances in which Gas Marketer sales representatives accurately portrayed the value of a fixed rate product, dissonance can arise in the consumer's mind that can distort their recollection of the sales transaction. If commodity prices had continued to increase, many consumers would remain satisfied with their Consumer Agreement because their purchase decision was "proved right" over time. Alternatively, when market prices fell dramatically after mid 2009, the price disparity between their contracted commodity rate and market price likely led many consumers to question their original decision. This internal conflict or dissonance regarding the consumer's belief that they should save money but are not, can result in people changing their actions, attitudes, and beliefs. As a result, some customers try to get out of contracts years after choosing them. Others reduce this internalized dissonance by blaming Gas Marketers or denying that they were adequately informed when they opted for a Consumer Agreement.

In summary, many Gas Marketer sales representatives led customers to believe that tremendous financial savings were available with fixed-rate products. However, FEI does not believe that all sales representatives employed this sales approach. Consumers may have given little thought to the purchase decision and even those consumers that initially understood their contract was not a guarantee of savings might re-evaluate their original decision months or years later. Hindsight is 20/20. An individual's re-evaluation of their original purchase can result in attempts to cancel contracts, changed attitudes, or adjusted beliefs about the product and the original transaction.

[3] Pearson Education, www.pearsoned.co.uk, specific reference at http://wps.pearsoned.co.uk/wps/media/objects/1452/1487687/glossary/glossary.html#C

10.3 Please confirm that due to the marketer (i) absorbing risk and (ii) requiring a significant return on investment in her marketing activities, it should be expected that in the long run and on average the utility offering would cost less than the marketer's offering. If unable to so confirm, please explain.

Response:

The Utilities are unable to confirm that over the long run and on average, the utility standard commodity rate offering would cost less than the marketer's offering. This is because there are a number of factors that determine the differential between the utility and marketer offerings. While both likely engage in hedging activity, the amount of hedging in the respective portfolios, the period hedged (i.e. hedging horizon), timing of the implementation of the hedging and the type of hedging instruments used will all influence the difference in the offerings. And if the market price volatility is significant, then these factors will have more of an influence on the difference.

The only certainty with respect to the difference between the utility standard rate offering and the marketers' fixed rate product is that the marketers will include within their rate offerings a mark-up for profit or return on investment. The utility passes on all costs as incurred, without mark-up, to customers.

10.4 If allowed to do so, would the utility be interested in investigating a utility fixed price offering to its bundled customers?

Response:

If allowed to do so, the Utilities would consider investigating a utility fixed price offering to its customers. . FEI did previously offer a Stable Rate product offering, which allowed residential customers to sign up for a one year fixed commodity rate, prior to the Customer Choice Program being made available to the residential rate class. However, this was discontinued at the end of 2007 after the Customer Choice Program was implemented.

11.0 Reference: Exhibit B-1, page 69

11.1 Did the utility have any difficulty in having enough physical gas for delivery to firm customers during the November 23, 2010 Sumas price spike?

Response:

No, the utility did not have any physical supply delivery issues during the Nov 23, 2010 price spike.

The Company's Annual Contracting Plan is designed to provide security of gas supply for all its customers under all weather conditions by incorporating a diverse range of supply, transportation and storage resources within its portfolio. Under certain situations, however, cuts to its gas supply contracts have occurred due to factors beyond the Utility's control such as events and outages on third party systems. For example, FEI experienced supply cuts in January 2011 due to plant outages on the Westcoast gathering system but was able to manage to meet its core load without any service interruptions by utilizing its market area storage resources. It also had its Tilbury LNG facility on standby in case more resources were required.

The location of load centers on the FEI system are distant from production areas resulting in the majority of supply to reach its market centers via transmission on third party pipeline systems that can be subject to occasional performance and deliverability issues during the winter months. As a result, the Utility's Gas Supply personnel plan and execute the resource stack to ensure that supply cuts on third party systems have minimal or no consequences to core customers on its system to the best of their ability. The Utility to date has served its core customers under all conditions, even during events on third party systems that have resulted in supply cuts to FEI.

11.2 Over the last 20 years, how many Sumas price "disconnects" have occurred?

Response: The graphs in the attached Figures 1 and 2 show Sumas daily prices relative to daily prices at Station 2 and AECO from November 1, 1996 to current, respectively. The Companies were not able to secure reliable pricing information prior to November 1, 1996.

As seen by the figures, historically, prices at the Sumas market hub have been much more volatile and subject to frequent disconnects from Station 2 and AECO prices. For illustrative purposes, the table below shows how often the Sumas daily price disconnected by more than $0.50 US/MMBtu over the daily Station 2 and AECO daily prices from November 1, 1996 to current. Over about the past 15 years, the Sumas daily price has disconnected by more than

$0.50 US/MMBtu over the Station 2 daily price about 21% of the time, and about 12% of the time over the AECO daily price.

Table 1: Sumas Price Disconnects from Station 2 and AECO Daily Prices

	Sumas-Station 2	Sumas-AECO
greater than $0.50 US/MMBtu disconnect	1,115	646
less than $0.50 US/MMBtu disconnect	4,134	4,603
Ratio of greater than $0.50 US/MMBtu disconnects	21%	12%

Aside from major excursions, Sumas prices generally trade at a premium to AECO prices in the winter months and this is due to the relative scarcity of supply due to infrastructure constraints in the Pacific Northwest region, especially at the Sumas interconnect. The following table illustrates the historical *seasonal* averages for monthly Sumas and AECO prices.

	Sumas ($US/MMBtu)	AECO ($US/MMBtu)	Sumas - AECO Premium
Nov04-Mar05	$6.11	$5.83	$0.27
Nov05-Mar06	$8.78	$8.86	-$0.09
Nov06-Mar07	$7.14	$6.40	$0.74
Nov07-Mar08	$8.02	$6.93	$1.09
Nov08-Mar09	$5.69	$5.05	$0.64
Nov09-Mar10	$5.49	$4.89	$0.60
Nov10-Mar11	$4.17	$3.70	$0.47

Figure 1: Sumas – Station 2 Daily Price Differential ($US/MMBtu)

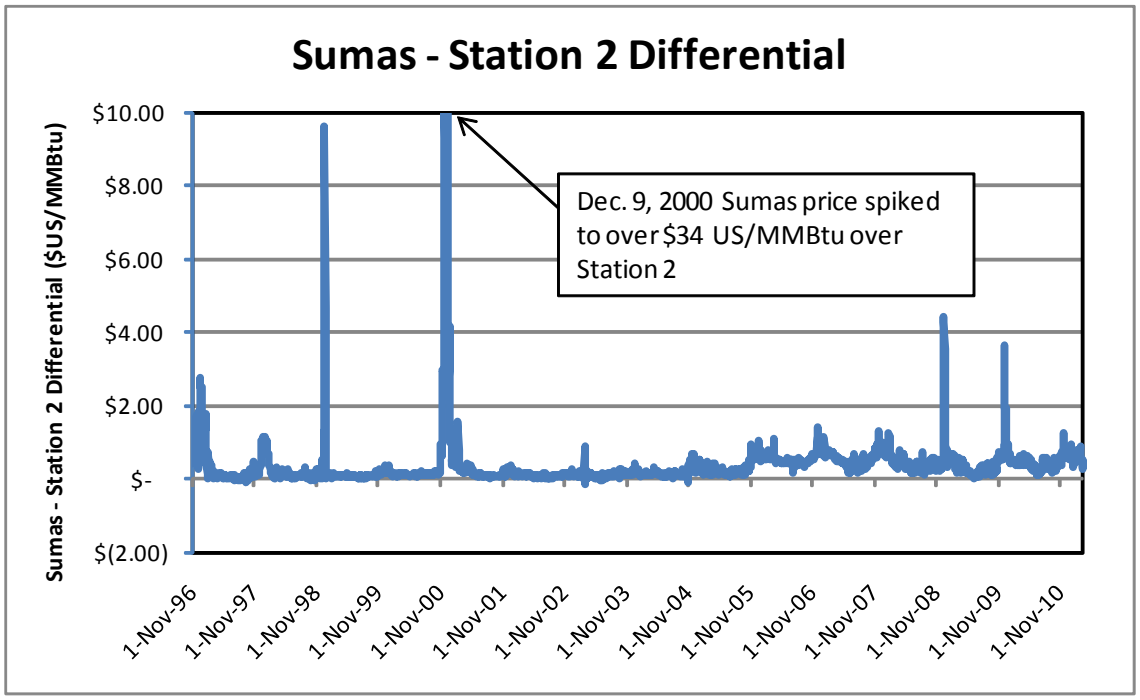
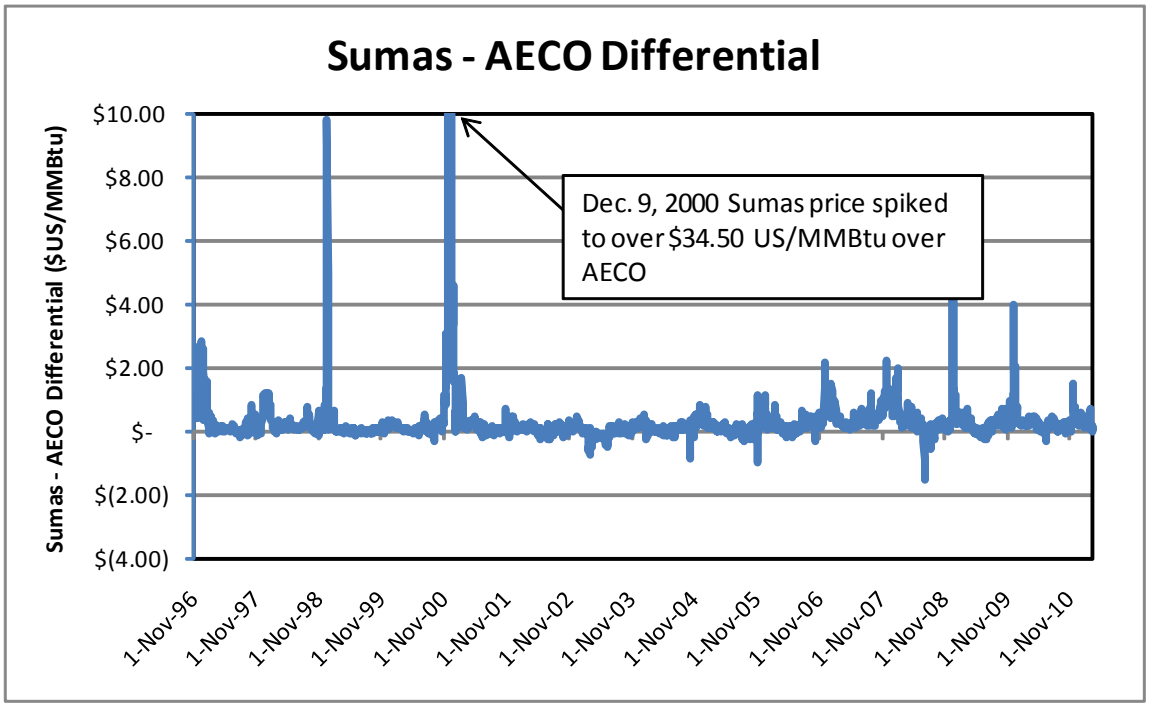


Figure 2: Sumas – AECO Daily Price Differential ($US/MMBtu)



12.0 Reference: Exhibit B-1, pages 71-72

12.1 Please explain why no Sumas-AECO basis swaps were undertaken for the years 2001/02-2004/05 inclusive.

Response:

For the winters of 2001/02, 2002/03, 2003/04 and 2004/05 the Companies implemented Sumas-NYMEX basis swaps, instead of Sumas-AECO basis swaps, as an alternate way of utilizing basis swaps to mitigate Sumas price exposure.

Since winter 2004/05, the Companies have utilized Sumas-AECO basis swaps, rather than Sumas-NYMEX basis swaps, because of the lower price volatility associated with the AECO monthly index as it has matured and become a more liquid pricing index. In a Sumas-NYMEX basis swap, the differential between the Sumas monthly index average and the NYMEX last day settle average, or last three day settle average, is fixed. However, with the Sumas-AECO basis swap, the differential between the Sumas monthly index average and the AECO monthly index average is fixed. The AECO monthly index is less volatile than the NYMEX last day, or last three day average, settle prices because the AECO monthly index is determined by the weighted average of all the deals transacted in the month prior to the delivery month, as compared to the last day, or last three days, prior to the month for NYMEX settles.

12.2 For each individual basis swap undertaken starting in 2000/01, please provide details including all direct and indirect costs including any fees paid, volumes hedged, identity of counterparty, and outcome.

Response:

For costs related to management and administration of the overall hedging strategy pursuant to the Price Risk Management Plan, please refer to the responses to BCUC IRs 1.4.3.1, 1.4.3.2, 1.4.3.3, and 1.4.3.4. There is no meaningful way to differentiate such costs between types of instruments or components of the Plan such as the basis swaps. In addition, given the nature of the instruments, there are no separate transaction fees or specific premiums paid to enter into basis swaps.

Please find details pertaining to each individual basis swap undertaken starting in 2000/01 and basis hedging costs/gains in Schedule 1 which follows. The name of the counterparty is not provided due to market sensitivity of disclosing the operations of other companies and that

information does not add to the discussion of hedging gains and costs of basis swaps. The outcome of these swaps are summarised on an annual basis in Table 1 below.

Table 1: Basis Swaps Outcomes

Year	Gains (Costs)
2000	0
2001	$(5,163,903)
2002	$(5,175,779)
2003	$(1,397,647)
2004	$(2,727,218)
2005	$(2,481,786)
2006	$651,378
2007	$1,608,145
2008	$(1,447,226)
2009	$(2,664,092)
2010	$(367,972)

Schedule 1: Historical Basis Swaps Information

Trade Date	Hedge Term	Index	Volume
Nov 30, 2000	Apr 01 - Oct 01	NYMEX Basis	2,140,000
Feb 22, 2001	Dec 01 - Jan 02	NYMEX Basis	310,000
Feb 22, 2001	Dec 01 - Jan 02	NYMEX Basis	310,000
Feb 26, 2001	Nov 01 - Mar 02	NYMEX Basis	755,000
March 7, 2001	Dec 01 - Jan 02	NYMEX Basis	310,000
July 12, 2001	Dec 01 - Jan 02	NYMEX Basis (1)	310,000
July 16, 2001	Dec 01 - Jan 02	NYMEX Basis (2)	(310,000)
July 24, 2001	Dec 01 - Jan 02	NYMEX Basis	310,000
July 24, 2001	Dec 01 - Jan 02	NYMEX Basis	310,000
July 26, 2001	Dec 01 - Jan 02	NYMEX Basis	310,000
August 7, 2001	Dec 01 - Jan 02	NYMEX Basis	310,000
August 8, 2001	Nov 01 - Mar 02	NYMEX Basis	755,000
August 9, 2001	Dec 01 - Jan 02	NYMEX Basis	310,000
August 15, 2001	Nov 01 - Mar 02	NYMEX Basis	755,000
September 14, 2001	Nov 01 - Mar 02	NYMEX Basis	755,000
September 14, 2001	Nov 01 - Mar 02	NYMEX Basis	(755,000)

Trade Date	Hedge Term	Index	Volume
April 4, 2002	Dec 02 - Jan 03	NYMEX Basis	310,000
May 2, 2002	Dec 02 - Jan 03	NYMEX Basis	310,000
May 21, 2002	Dec 02 - Jan 03	NYMEX Basis	310,000
Aug 15, 2002	Nov 02 - Feb 03	NYMEX Basis	600,000
Aug 23, 2002	Nov 03 - Mar 04	NYMEX Basis	755,000
Sep 23, 2002	Nov 03 - Mar 04	NYMEX Basis	755,000
Dec 16, 2002	Jan 03 - Mar 03	NYMEX Basis	900,000
Dec 16, 2002	Jan 03 - Mar 03	NYMEX Basis	900,000
Dec 17, 2002	Jan 03 - Mar 03	NYMEX Basis	900,000
Dec 17, 2002	Jan 03 - Mar 03	NYMEX Basis	900,000
Dec 17, 2002	Jan 03 - Mar 03	NYMEX Basis	900,000
Dec 17, 2002	Jan 03 - Mar 03	NYMEX Basis	900,000
Dec 18, 2002	Jan 03 - Mar 03	NYMEX Basis	450,000
Dec 18, 2002	Jan 03 - Mar 03	NYMEX Basis	450,000
Dec 18, 2002	Jan 03 - Mar 03	NYMEX Basis	450,000
Dec 18, 2002	Jan 03 - Mar 03	NYMEX Basis	450,000
Dec 18, 2002	Jan 03 - Mar 03	NYMEX Basis	405,000
Dec 18, 2002	Jan 03 - Mar 03	NYMEX Basis	405,000
May 22, 2003	Apr 04 - Oct 04	NYMEX	1,070,000
May 22, 2003	Apr 04 - Oct 04	Nymex/Sumas	(1,070,000)
May 27, 2003	Apr 04 - Oct 04	NYMEX	1,070,000
May 27, 2003	Apr 04 - Oct 04	Nymex/Sumas	(1,070,000)
Jun 12, 2003	Dec 03 - Feb 04	Nymex/Sumas	(455,000)
Jun 12, 2003	Dec 03 - Feb 04	NYMEX	455,000
Jun 26, 2003	Dec 03 - Feb 04	NYMEX	455,000
Jun 26, 2003	Dec 03 - Feb 04	Nymex/Sumas	(455,000)
Jun 27, 2003	Apr 05 - Oct 05	NYMEX	1,070,000
Jun 27, 2003	Apr 05 - Oct 05	Nymex/Sumas	(1,070,000)
Aug 07, 2003	Nov 04 - Mar 05	Nymex/Sumas	(755,000)
Aug 07, 2003	Nov 04 - Mar 05	NYMEX	755,000
Aug 11, 2003	Apr 05 - Oct 05	Nymex/Sumas	(1,070,000)
Aug 11, 2003	Apr 05 - Oct 05	NYMEX	1,070,000
Jun 10, 2004	Nov 04 - Feb 05	Nymex/Sumas	300,000
Jun 18, 2004	Nov 04 - Feb 05	Nymex/Sumas	300,000
Jul 06, 2004	Nov 04 - Feb 05	Nymex/Sumas	511,800
Jul 20, 2004	Nov 04 - Feb 05	Nymex/Sumas	511,800

Trade Date	Hedge Term	Index	Volume
Aug 11, 2004	Nov 04 - Feb 05	Nymex/Sumas	480,000
Aug 19, 2004	Nov 04 - Feb 05	Nymex/Sumas	284,400
Oct 28, 2004	Nov 05 - Feb 06	AECO/Sumas	568,860
Oct 28, 2004	Nov 05 - Feb 06	AECO/Sumas	568,860
Nov 10, 2004	Nov 05 - Feb 06	AECO/Sumas	600,000
Feb 15, 2005	Nov 05 - Feb 06	AECO/Sumas	600,000
Jun 08, 2005	Nov 05 - Feb 06	AECO/Sumas	300,000
Jul 06, 2005	Nov 05 - Feb 06	AECO/Sumas	300,000
Aug 10, 2005	Nov 06 - Mar 07	AECO/Sumas	755,000
Aug 15, 2005	Nov 05 - Mar 06	AECO/Sumas	604,000
Aug 16, 2005	Nov 05 - Feb 06	AECO/Sumas	360,000
Sep 13, 2005	Nov 05 - Feb 06	AECO/Sumas	360,000
Sep 13, 2005	Nov 05 - Mar 06	AECO/Sumas	541,033
Nov 15, 2005	Nov 06 - Mar 07	AECO/Sumas	755,000
Jan 18, 2006	Nov 06 - Mar 07	AECO/Sumas	377,500
Jan 19, 2006	Nov 06 - Mar 07	AECO/Sumas	377,500
Mar 27, 2006	Nov 06 - Mar 07	AECO/Sumas	679,500
May 09, 2006	Nov 06 - Mar 07	AECO/Sumas	755,000
Jul 12, 2006	Nov 06 - Mar 07	AECO/Sumas	634,200
Jul 18, 2006	Nov 06 - Feb 07	AECO/Sumas	852,000
Aug 23, 2006	Nov 06 - Feb 07	AECO/Sumas	852,000
Sep 14, 2006	Nov 06 - Feb 07	AECO/Sumas	852,000
Oct 04, 2006	Nov 06 - Feb 07	AECO/Sumas	852,000
Oct 17, 2006	Nov 07 - Mar 08	AECO/Sumas	760,000
Dec 14, 2006	Nov 07 - Mar 08	AECO/Sumas	684,000
Feb 16, 2007	Nov 07 - Mar 08	AECO/Sumas	668,800
Apr 04, 2007	Nov 07 - Mar 08	AECO/Sumas	638,400
Jul 10, 2007	Nov 07 - Mar 08	AECO/Sumas	646,000
Aug 10, 2007	Nov 07 - Feb 08	AECO/Sumas	1,210,000
Aug 17, 2007	Nov 07 - Feb 08	AECO/Sumas	1,210,000
Sep 12, 2007	Nov 07 - Mar 08	AECO/Sumas	646,000
Sep 19, 2007	Nov 07 - Feb 08	AECO/Sumas	1,016,400
Feb 26, 2008	Nov 08 - Mar 09	AECO/Sumas	755,000
Apr 08, 2008	Nov 08 - Mar 09	AECO/Sumas	755,000
May 27, 2008	Nov 08 - Mar 09	AECO/Sumas	755,000
Jun 24, 2008	Nov 08 - Feb 09	AECO/Sumas	840,000

Trade Date	Hedge Term	Index	Volume
Jul 08, 2008	Nov 08 - Mar 09	AECO/Sumas	755,000
Jul 25, 2008	Nov 08 - Feb 09	AECO/Sumas	840,000
Aug 13, 2008	Nov 08 - Feb 09	AECO/Sumas	840,000
Sep 05, 2008	Nov 08 - Mar 09	AECO/Sumas	736,880
Sep 05, 2008	Nov 08 - Feb 09	AECO/Sumas	888,000
Jan 06, 2009	Nov 09 - Mar 10	AECO/Sumas	755,000
Apr 28, 2009	Nov 09 - Mar 10	AECO/Sumas	755,000
Jun 18, 2009	Nov 09 - Mar 10	AECO/Sumas	755,000
Jun 23, 2009	Nov 09 - Feb 10	AECO/Sumas	900,000
Jul 09, 2009	Nov 09 - Feb 10	AECO/Sumas	900,000
Jul 16, 2009	Nov 09 - Mar 10	AECO/Sumas	528,500
Aug 28, 2009	Nov 09 - Mar 10	AECO/Sumas	595,544
Sep 15, 2009	Nov 09 - Feb 10	AECO/Sumas	900,000
Sep 28, 2009	Nov 09 - Feb 10	AECO/Sumas	900,000
Jan 13, 2010	Nov 10 - Mar 11	AECO/Sumas	604,000
Apr 15, 2010	Nov 10 - Mar 11	AECO/Sumas	755,000
Jul 30, 2010	Nov 10 - Mar 11	AECO/Sumas	755,000
Aug 05, 2010	Nov 10 - Mar 11	AECO/Sumas	755,000
Aug 05, 2010	Nov 10 - Feb 11	AECO/Sumas	900,000
Aug 11, 2010	Nov 10 - Feb 11	AECO/Sumas	900,000
Aug 12, 2010	Nov 10 - Mar 11	AECO/Sumas	755,000
Aug 30, 2010	Nov 10 - Feb 11	AECO/Sumas	900,000
Sep 24, 2010	Nov 10 - Feb 11	AECO/Sumas	900,000

12.3 To FortisBC's knowledge, did any of the utility's counterparties engage contemporaneously in any hedging or other financial activities with affiliated unregulated entities?

Response:

Please refer to BCOAPO IR 1.2.10.

13.0 Reference: Exhibit B-1, page 73

13.1 Please give the details of the market indexes used.

Response:

The Companies are assuming that the question is referring to market index prices relating to physical purchases of commodity supply under the ACPs.

The Companies primarily purchase physical gas supply at Station 2, Huntingdon, and Alberta using a combination of monthly and daily priced contracts.

Monthly priced gas at Station 2 and Alberta are priced off the AECO monthly index plus the prevailing market factor at the time of entering into the deal while monthly priced deals at Huntingdon are priced off the Sumas Monthly index plus the prevailing market factor at the time of entering into the deal.

Daily priced supply at Station 2 and Huntingdon are priced off the Platt's Gas Daily Daily publication index while pricing in Alberta utilizes the Canadian Gas Price Reporter publication index. The Companies also purchase a portion of peaking supply during the winter months at Kingsgate for use during extreme winter conditions priced at the Platt's Gas Daily Daily Kingsgate index price.

13.2 Please indicate how using a market-indexed price reduces volatility.

Response:

Market indexed price supply does not provide any volatility reducing functions. One of the ACP's functions is to contract for safe and reliable supply while minimizing costs within its portfolio. The ACP secures physical supply that is deemed be safe, efficient, and cost effective to serve load purposes at monthly indexed prices and, as stated on page 73 of the Review Report, the PRMP's function is to remove the inherent volatility in indexed based (i.e. market based) prices using various financial derivatives available at its disposal.

14.0 Reference: Exhibit B-1, page 78

14.1 Please confirm that storage could be used for each winter season to mitigate commodity price volatility.

Response:

Storage resources are considered a part of the midstream portfolio and the costs associated with storage are reflected in the Midstream Cost Reconciliation Account ("MCRA") and are recovered from all customers in Rate Schedules 1 to 7. FortisBC does transact a relatively small volume of hedging for its midstream portfolio; however a large majority of FortisBC's hedging activities are for the CCRA portfolio which is 100% load factor baseload supply; baseload supply is provided by Gas Marketers and under the FortisBC CCRA portfolio, which is then managed through the FortisBC midstream assets.

Storage can and should be considered an important component of an effective price risk management strategy. Storage provides a physical hedge by realizing and locking in the differential between summer prices and winter prices with the intent being to inject gas in the summer months when gas prices are generally lower for withdrawal in the colder winter months when prices generally tend to be higher.

15.0 Reference: Exhibit B-1, Appendix A

15.1 It appears that the analysis almost entirely consists of Monte Carlo simulations. Is this an accurate statement?

Response:

The consultant RiskCentrix performed several kinds of analysis in developing the recommended hedging strategy. Monte Carlo simulations were first used as an effective and industry accepted method of simulating price movements based on currently known variables such as current forward prices, observed or implied volatility, and term to maturity. RiskCentrix then performed extensive analysis involving testing of the hedging strategies against the simulated price paths to determine their effectiveness. Furthermore, as part of the enhanced hedging strategy, the use of Value at Risk ("VaR") analysis will be used when formulating defensive hedging decisions. VaR analysis will incorporate observed market price volatility, term to maturity, and defined confidence intervals to formulate defensive hedging decisions when market price and volatility increases threaten to breach the predefined defensive tolerance triggers, which are based on consideration of customers' bill change tolerances and competitive benchmarks.

15.2 Please provide empirical support for the claim that actual gas commodity market prices are distributed lognormally.

Response:

Price distributions for natural gas are assumed to follow a lognormal distribution since the properties of the lognormal function do not allow for values to go below zero and prices to the upside are unbounded.

The lognormal distribution rather than a normal distribution is a legitimate assumption for price data, in that prices cannot be less than zero in reality. Figure 1 below illustrates a typical lognormal distribution with standard deviation equal to 1 and a mean of 1.

Figure 1: Lognormal Distribution – (Std. Deviation = 1, Mean = 1)

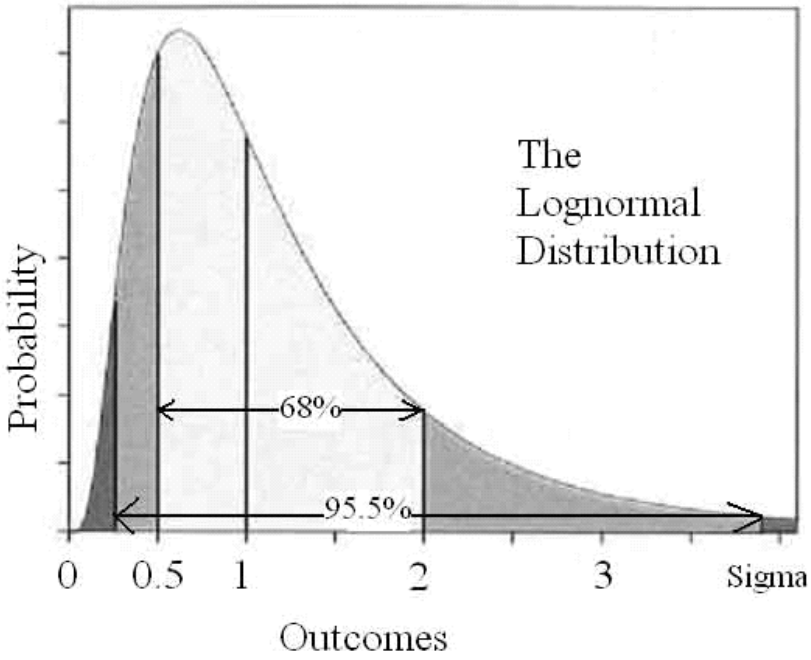
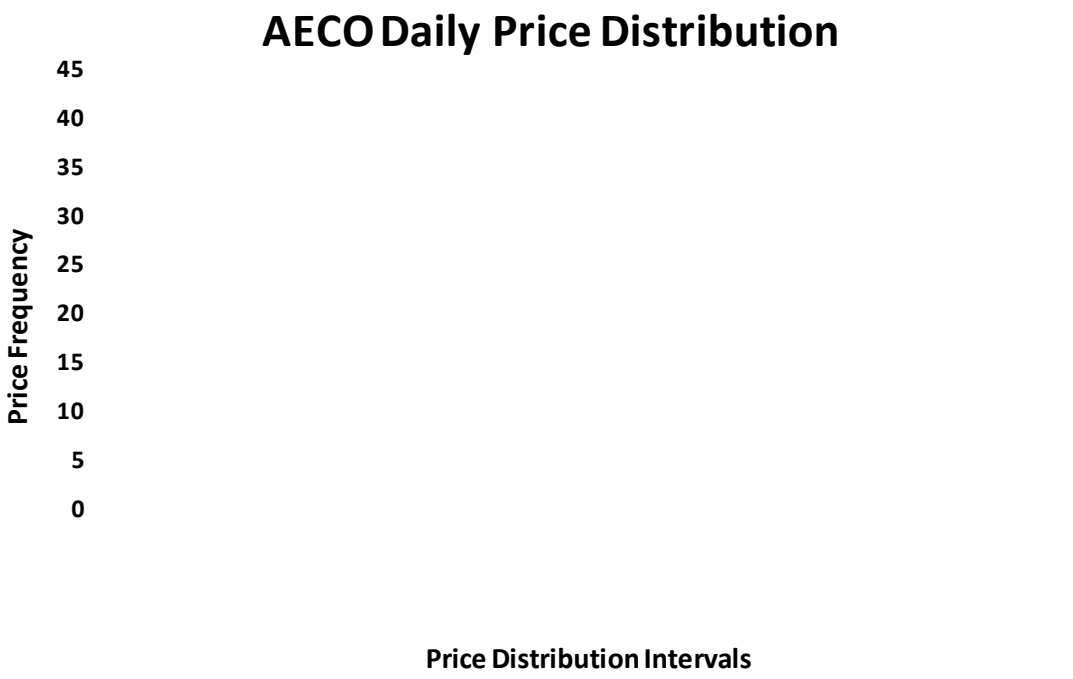


Figure 2 below illustrates a distribution of price settles of the AECO daily price from November 1, 2001 to March 1, 2011. Note the frequency of prices is distributed generally in a lognormal distribution, as displayed above. A lognormal function is the best available tool over other functions to help model distribution of prices and is an industry-wide accepted function to model price distributions.

Figure 2: Distribution of AECO Daily Prices



15.3 Please indicate where the direct and indirect costs of both planning and implementing the various strategies have been taken into account.

Response:

As discussed in the response to BCUC IR 1.4.3.1, the indirect costs, or those relating to price risk management and administration, are included within the cost of gas flowed through to customers. On a per customer basis, these are not material in terms of annual bill costs. The indirect costs associated with the proposed enhanced hedging program would not be materially different than those costs described in that IR response.

The direct costs, or those relating to hedging gains or costs, have been taken into account by the analysis performed by the consultant RiskCentrix, and discussed within Section 7.1.3 of the Review Report. Given the uncertainty of market gas prices going forward, RiskCentrix

simulated future market price scenarios and then tested the enhanced hedging strategy against those price scenarios. The results, presented in Table 18 on page 88 of the Review Report, illustrate the potential hedging gains and costs based on a 95% probability confidence interval. The results also show that for the recommended hedging strategy the potential hedging costs in the extremely low market price scenario (where prices fall to $1/GJ) are significantly less than those incurred on an annual basis over the past few years.

It should be noted that the RiskCentrix analysis was based on the performance of the proposed enhanced hedging strategy as a whole, including the programmatic, value, defensive and basis components, rather than based on the performance of one of these components in isolation. The components work together in combination to meet the objectives.

16.0 Reference: Exhibit B-2, page 2

16.1 Is value hedging similar to a "stop loss" order?

Response:

A stop loss order is defined as an order to buy (or sell) a security once the price of the security has climbed above (or dropped below) a specified stop price. When the specified stop price is reached, the stop order is entered as a market order (no limit). This means the trade will definitely be executed, but not necessarily at or near the stop price, particularly when the order is placed into a fast-moving market, or if there is insufficient liquidity available relative to the size of the order.

In this regard, FortisBC does not view a stop loss order as similar to value hedging and FortisBC does not employ stop loss orders when at or near value hedging targets. Instead, FortisBC will indicate to its financial counterparties of its intent to enter into a hedge if the price reaches the value hedging target. If the value hedging price is reached FortisBC will solicit offers from a number of counterparties and then select the best counterparty with which to do the deal giving consideration to offered price, current credit exposure, and term to maturity of the deal.

16.2 Please indicate where the direct and indirect costs of both planning and implementing the various strategies have been taken into account in the recommendations.

Response:

Please refer to the response to BCOAPO IR 1.15.3.

16.3 Please provide examples that show typical direct and indirect costs (writing, fees, legal, financial, administrative, regulatory etc.) of the various options available and considered, e.g., for programmatic hedging, call options, costless collars, basis swaps, value hedging etc.

Response:

Please refer to the response to BCOAPO IR 1.15.3.

17.0 Reference: Exhibit B-2, General

17.1 Does the regulated utility currently have any hedging arrangements that involve an affiliated counterparty? If so, please provide details.

Response:

No, the Utilities do not currently have nor do they plan to have any commodity hedging arrangements with affiliated counterparties.

17.2 Does the regulated utility currently have any hedging arrangements that involve a third party counterparty which has any hedging or financial arrangements with an affiliated counterparty? If so, please provide details.

Response:

It is understood that this question is asking if the regulated utility has any hedging arrangements with a third party counterparty that is acting simply as a middleman for arrangements between the regulated utility and an affiliated counterparty. No, there are no such arrangements in place nor do the Utilities expect to put such arrangements in place at anytime in the future. Please also see the response to BCOAPO 1.12.3.

17.3 Going forward, does the regulated utility expect to have any hedging arrangements that involve an affiliated counterparty? If so, please provide details.

Response:

Please refer to the response to BCOAPO IR 1.17.1.

17.4 Going forward, does the regulated utility expect to have any hedging arrangements that involve a third party counterparty which has any hedging or financial arrangements with an affiliated counterparty? If so, please provide details.

Response:

Please refer to the response to BCOAPO IR 1.17.2.

17.5 For each year of the plan going forward, please provide (i) expected total bill volatility without hedging, all else equal, (ii) expected total bill volatility with hedging, all else equal, and (iii) the total costs of the hedging exercise.

Response:

The Utilities do not have a way to measure expected total bill volatility with and without hedging for its portfolio however, the most relevant metrics to measure potential outcomes of various scenarios were performed by the RiskCentrix consultant. Table 18 on page 88 of the Review Report, also shown below, performed analysis of different hedging scenarios under different simulated market price conditions in order to determine some ranges for expected bill volatility and costs based on a 95% confidence interval.

The graph shows the maximum expected volatility reduction and bill increase and maximum out-of-the market costs and option premium expenditures. Without hedging, the bill increases would be the full columns in the graph and hedging and options costs would be zero. FEI is recommending strategy G as the optimal balance of meeting the primary objectives of the PRMP and minimizing potential hedging costs. Further details of the RiskCentrix analysis is provided in Appendix A of the Review Report.

Finally, for indirect costs associated with the hedging program, please refer to the response to BCUC IR 1.4.3.1.

Figure 1: Hedging Strategy Scenario Results